FILED
8-09-16
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development of, California Renewables Portfolio Standard Program.	Rulemaking 15-02-020 (Filed February 26, 2015)

REPLY COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON LEAST COST, BEST FIT REFORM

JANET S. COMBS
CAROL SCHMID-FRAZEE

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1337
Facsimile: (626) 302-1935
E-mail: Carol.SchmidFrazee@sce.com

Dated: **August 9, 2016**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development of, California Renewables Portfolio Standard Program.	Rulemaking 15-02-020 (Filed February 26, 2015)

REPLY COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON LEAST COST, BEST FIT REFORM

I.

INTRODUCTION AND EXECUTIVE SUMMARY

Pursuant to Ordering Paragraph No. 3 of the Administrative Law Judge's Ruling Accepting into the Record Energy Division Staff Paper on Least-Cost Best-Fit Reform for Renewables Portfolio Standard Procurement and Requesting Comment, dated June 22, 2016 ("ALJ's Ruling"), Southern California Edison Company ("SCE") hereby submits its reply comments on the parties'[1] opening comments on Questions 2-18 set out in the Staff Paper attached to the ALJ's Ruling.

[1] In addition to SCE, the parties filing opening comments on the Staff Paper included: Independent Energy Producers Association ("IEP"), California Wind Energy Association ("CalWEA"), Ormat Technologies ("Ormat"), Office of Ratepayer Advocates ("ORA"), Calpine Corporation ("Calpine"), Transwest Express LLC ("Transwest"), L. Jan Reid ("Jan Reid"), Bay Area Municipal Transmission Group ("BAMx"),California Biomass Energy Alliance ("CBEA"), San Diego Gas & Electric Company ("SDG&E"), Center for Energy Efficiency and Renewable Technologies ("CEERT"), Green Power Institute ("GPI"), and Pacific Gas and Electric Company ("PG&E").

II.

ALTERNATIVE OPTIONS TO TOD FACTORS CAN INFORM THE MARKET OF WHEN POWER IS MOST VALUABLE

A. Utilities Can Communicate Hours of Peak Need to the Market Without Using TOD Factors for Contract Payments

1. TOD Factors Are Not Needed to Accurately Value Potential Projects

GPI and CBEA suggest that utilities should use Time of Delivery ("TOD") factors for accurate valuation of RPS resources.[2] GPI states that "TOD factors serve the useful function of allowing bids from generators with differing output profiles to be compared on a comparable basis."[3] CBEA states that TOD factors "allows bids from generators with different output profiles to be ranked on a comparable basis."[4] To the contrary, TOD factors are not needed to accurately or comparably rank the benefit of different projects or types of generation.

From a valuation perspective, the LCBF methodology already accounts for the different value of energy and capacity during peak and non-peak hours through the use of forward price curves for energy and capacity that are used for benefits calculations. Thus, TOD factors are not needed to accurately capture the energy and capacity value of different resources with different generation profiles.

TOD factors are only used in the valuation process to calculate expected contract payments based on the bid price of a resource. As explained in SCE's opening comments,[5] renewable developers design their bids to generate a rate of return and demonstrate a steady state of cash flows to facilitate financing for their projects.

---

[2] *See* GPI, p. 9 and CBEA, p. 5.
[3] GPI, p. 9.
[4] CBEA, p. 5.
[5] SCE's Opening Comments, p. 9.

Developers will typically adjust their bid prices so that the post-TOD payments reflect their cash flow needs.[6] The expected revenues a project needs stay the same regardless of what, if any, TOD factors are used.[7] Accordingly, if TOD factors are not used to calculate contract payments, developers will adjust their bids prices to ensure that the non-TOD adjusted expected contract payments will meet their cash flow needs, and there will be no need to use TOD factors in the valuation process to calculate expected contract payments.

2. TOD Factor-Based Contract Payments Are Not Effective Operational Incentives

CalWEA, Calpine, and Jan Reid expressed doubt about the effectiveness of TOD factor-based contract payments to incent optimal generation for non-dispatchable renewable resources.[8] CalWEA states that "time-differentiated energy payments serve little purpose in optimizing renewable energy operations since most renewable fuels cannot be controlled."[9] Calpine also opines "[i]n operations, TOD factors may not be the most effective means to incent production at times that a resource has the greatest expected value to the grid."[10] Jan Reid adds that "only non-intermittent resources can shift production to different time periods."[11]

SCE agrees with these parties that TOD factors are not effective to incent dispatch of non-dispatchable renewable resources. TOD factors may incentivize certain non-intermittent or dispatchable renewable resources to optimize their dispatch for the purpose of maximizing their payments. However, fixed TOD factors do not necessarily

---

6 *Id*.
7 *Id*.
8 *See* CalWEA, p. 6, Calpine, p. 5, and Jan Reid, p. 7.
9 CalWEA, p. 6.
10 Calpine, p. 5.
11 Jan Reid, p. 7.

accurately reflect future grid conditions and may incentivize a dispatch that does not optimally support grid requirements. Forecasted TODs for long-term contracting are based on SCE's outlook of energy market forecasts for the length of the contract (15-20 years). As ORA notes, "there is the risk that TOD factors may become outdated with longer term contracts as a utility's load profile changes."[12] Changes in policy direction (e.g., renewable development, high growth for electric vehicles, high penetration of distributed resources) can impact the accuracy of forecasted TOD factors during the length of a contract. For example, early renewable resources received incentives for mid-day generation – a time now expected to have some of the highest over-generation. Not only does use of fixed TOD factors not optimize generation of non-dispatchable resources, but it may actually provide perverse incentives, as system needs change. Other mechanisms, like curtailment provisions, are more powerful to incentivize the dispatch of renewable resources when most needed over the full contract length.[13]

3. IOUs Can Communicate Hours of Peak Need Without Using TOD Factors for Contract Payments

Calpine, CalWEA, and IEP indicated that TOD factors provide useful guidance during the building and development phase.[14] Calpine stated that "to the extent that TOD factors reflect the forward price curve assumptions that the IOUs actually use in valuation, they provide aggregated information about the periods in which energy is valuable and encourage developers to develop projects that will produce energy in those periods."[15] CalWEA stated "[w]hile the operational changes that a project operator can make are very limited once the project is built, providing signals about the values being

[12] ORA, p. 4.
[13] *See* SCE Opening Comments p. 8-10.
[14] *See* Calpine, p. 4, CalWEA, p. 8, and IEP, pp. 8-9.
[15] Calpine, p. 4.

ascribed will enable developers to optimize the projects that they bid (which, in turn, will benefit ratepayers)".[16] IEP stated "[b]idders can and will respond to the incentives represented by the TOD factors. If the buyer values deliveries in late afternoon more highly and sets the TOD factors accordingly, for example, solar photovoltaic project developers will respond by orienting their panels to the west or integrating storage into the facility to increase production when deliveries are most highly valued."[17] SCE agrees with CalWEA, Calpine, and IEP that communication of high value energy periods at an aggregated level to project developers may provide helpful guidance during the project development phase. There is value in providing this information and SCE plans to continue to communicate that information to bidders.

However, TOD factors do not need to be used for contract payment in order for this communication to occur. Instead, in order to continue to provide guidance for project development. SCE proposes to provide additional information at an aggregate level similar to TOD factors for communication purposes only and discontinue their use for contract payments. SCE will develop these new aggregate factors and share them with developers during the bidding process so that developers can identify the blocks of hours providing the most value to SCE's customers over time. Unlike the current fixed TOD factors, SCE will be able to provide more detail on how it expects the factors to change over the course of the procurement horizon. These factors should only be used for providing direction to developers while a project is in the development phase. As discussed above, fixed TOD factors do not provide strong incentives after a project is in operation. Hence the Commission should discontinue the use of TOD factors in renewable Power Purchase Agreements ("PPAs").

---

[16] CalWEA, p. 8.
[17] IEP, p. 9.

B. IOUs Do Not Need to Provide the RA Capacity Curves Used in Valuations

Contrary to the claims of CalWEA and Transwest,[18] developers do not need to fully understand the trade-off between transmission upgrade costs and capacity value, including complete information on how a utility values capacity, to make a determination of whether to opt for Energy-Only ("EO") or Full Capacity Deliverability Status ("FCDS"). CalWEA states that "the developer must know the value of the RA capacity to the IOUs in addition to the cost of the upgrades."[19] Transwest also adds that "[f]or a developer to accurately identify the value of obtaining FCDS, it must be able to compare the RA capacity value of a project and/or cluster of projects to the incremental cost of obtaining FCDS."[20] CalWEA and Transwest are incorrect. Complete capacity value information is not needed to make this trade-off, developers can simply bid a project as EO and as FCDS and see which bid wins. Additionally, as stated in SCE's opening comments, if capacity forward price curves were to become public, it would become easier for bidders to have a similar understanding of how to price for marginally cost effective bids, resulting in higher prices.[21]

1. Rather Than Providing Developers Exact RA Capacity Price Curves Developers Should Bid Multiple Deliverability Options

SCE supports Calpine's suggestion that allowing developers to bid multiple deliverability options could provide a good alternative to providing confidential utility information.[22] Calpine notes that there could be benefit from "[a]llowing developers to submit multiple offers for the same resource with differing degrees of deliverability."[23]

---

[18] *See* CalWEA, p. 5 and Transwest, p. 6.
[19] CalWEA, p. 5.
[20] Transwest, p. 6.
[21] SCE, pp. 6, 7.
[22] Calpine, p. 8.
[23] *Id.*

As part of the Generation Interconnection Process, developers can select FCDS, Partial Deliverability, or EO Deliverability Status with their initial generation interconnection request. When developers receive the results of their Phase II interconnection study, they also receive information informing them of the minimum operational requirements for EO interconnection. If developers are interested in pursuing both a FCDS and EO status projects, they can use the information provided from the operational requirements to bid an EO project, and use the information from the Phase II study to bid a FCD project. Moreover, if developers choose to pursue an EO option, they can, during the CAISO's annual process, obtain information about the additional costs of upgrading their project to FCDS. Thus, developers already have the information and flexibility that they need to bid both or either EO of FCD projects. This flexibility will provide the dual benefit of (1) not forcing developers to commit to one deliverability status and (2) providing the buyer additional project options, which will allow them to choose the projects that provide the highest value to customers.

2. Providing Utility Capacity Curves May Not Impact Deliverability Status Decisions

As stated above, CalWEA and Transwest assert that developers need to understand the relative costs of transmission upgrades and value of capacity in order to make decisions about deliverability status. However, SCE's experience is that additional information on capacity value may not impact a developer's decision about whether to seek guaranteed FCDS (known as "Option B" in the CAISO's Generator Interconnection and Deliverability Allocation Procedures ("GIDAP") protocols). Indeed, CalWEA states later in their comments that "[b]ecause deliverability upgrades are in most cases extremely costly, very few developers select Option B in the GIDAP process, which guarantees FCD status. Therefore, knowing the value that the utilities will award for having FCD status is unlikely to change developers' decisions whether to select Option A or B in most cases."[24]

SCE agrees with CalWEA that additional information on capacity value is unlikely to change developer's decisions. This is due to the high costs that would be borne by developers if transmission upgrades were needed to achieve FCDS. SCE's experience is that, in the GIDAP process, developers have frequently picked "Option A," which offers developers whichever deliverability status can be achieved at no cost, instead of "Option B," which may cause developers to incur transmission upgrade costs. SCE expects that knowledge of SCE's valuation of RA capacity would be unlikely to change a developer's choice from Option A to Option B in the GIDAP. As a result, developers do not need exact information on capacity pricing to make this choice.

3. SCE Agrees With PG&E That Rough Benchmarks of Capacity Value Already Exist

In its opening comments, PG&E states that it "supports the use of publicly-available capacity price forecasts, including those developed by third-party consultant to the Commission, as a benchmark to assess the reasonableness of the proprietary and market-sensitive capacity price forecasts that each IOU uses in its LCBF evaluation."[25] SCE agrees with PG&E and supports the use of these publicly-available price forecasts for reference purposes. Publicly-available capacity price forecasts should provide sufficient information to developers who are trying to understand the tradeoffs between EO and FCDS projects. Accordingly, it is not necessary for the utilities to share the specific capacity price curves used in their solicitations.

---

[24] CalWEA, p. 9.
[25] PG&E, p. 3.

4. Jan Reid's Proposal to Have Utilities Value Capacity After a Bid is Not Chosen is Unnecessary

Jan Reid outlines a proposal to help developers understand the relative value of capacity versus transmission upgrades.[26] While SCE appreciates the goal of Jan Reid's proposal to provide additional information to developers to help them understand whether FCDS would have been cost effective, this process is not necessary. If developers submit both a FCDS and EO bid for the same project, as outlined above, developers will have the information they may want about the relative value of the different deliverability statuses. Moreover, unlike in Jan Reid's proposal, developers will have the opportunity for both projects to participate and potentially to have one get selected in a solicitation. Furthermore, disclosing specific values may have an adverse impact on the competitiveness of future solicitations.

III.
CONFIDENTIALITY RULES ARE NEEDED TO PROTECT CUSTOMERS

The Commission should reject the recommendations of IEP, CalWEA, Calpine, and GPI to establish publicly available capacity prices for use in evaluating RPS bids.[27] Following the devastating financial crisis of 2000-2001, the State's Department of Water Resources had to take over the procurement of power from the utilities because they did not have the capability to do it because of gaming in the electricity market.[28] As a result, the State enacted Public Utilities Code Section 454.5(g) requiring the Commission to adopt "appropriate procedures to ensure the confidentiality of any market sensitive information submitted" to the commission as part of the procurement process. In D.06-06-066, the Commission adopted a Matrix identifying information that was market sensitive and should be protected from disclosure. Section VIII.B of the Matrix

---

26 Jan Reid, p. 12.
27 *See* IEP, pp. 5-6, CalWEA, p. 2, Calpine, p. 7, and GPI, p. 5.
28 Governor's Proclamation of January 17, 2001 and AB 1X, as well as D.02-11-022, pp. 5-7.

protects "specific quantitative analysis involved in scoring and evaluation of participating bids" for three years after the winning bidders are selected.

IEP, CalWEA, Calpine, and GPI all inappropriately advocate making public capacity prices used in RPS bid evaluation before the bids are even submitted.[29] Making capacity prices public would increase the probability of gaming of bids to the detriment of customers. Confidential information used in bids must remain confidential to protect bundled customers.

A. IOUs Should Use Confidential Utility-Specific Information in Evaluating RPS Bids

The IOUs should use their own confidential utility-specific information for evaluation of RPS bids. Each IOU's bid evaluation should be based on that IOU's forecast of prices for its service territory, its load forecast, and its local and system needs. A public capacity price will not take into account each IOU's understanding of the market in its service territory and the value to it of generation resources in certain locations. This type of information is market sensitive, pursuant to Public Utilities Code Section 454.5(g) and D.06-06-066. It should not be made public, but it should be used to evaluate RPS bids in order to choose the projects that will most benefit bundled customers.

If the Commission wants to develop publicly-available capacity prices as a check on the IOUs' market sensitive price forecasts, it can do so. However, the Commission should not mandate use of such prices by the IOUs in their bid evaluations. Requiring the IOUs to use publicly-available price forecasts in their valuation methodologies would result in less accurate valuation of RPS resources, the potential for gaming, and potentially higher costs to customers.

---

[29] *See Id.*

B. Maintaining the Confidentiality of Market Sensitive Information Protects Bundled Customers

Bundled customers will suffer if market sensitive price forecasts and valuation information is released to market participants. ORA asks the key question associated with making public capacity prices used in bid evaluation: "How will the Commission preserve market competition that yields the lowest prices for ratepayers?"[30] There is no way to preserve market competition that yields the lowest prices for customers when market participants have all of the information that they need to manipulate their bids.

IEP asserts that the utilities should provide information about precisely how they will value different aspects of competitive bids, asserting that this will not lead to "gaming" of bids.[31] IEP is wrong. In D.06-06-066, the Commission noted that: "Confidentiality protections are essential to avoid a repetition of electricity market manipulation."[32] Developers can use information about how the IOUs will value different aspects of competitive bids to have their bid win in any solicitation. It is simple logic that some developers will use information available to them for their own advantage. Developers have no responsibility to protect bundled customers, but they do have a responsibility to their owners and financiers to obtain the best possible return on investment.

Making market sensitive information available to developers will not necessarily allow them to cut prices in their bids. CalWEA asserts that making capacity prices used in valuation public will enable developers to pay for FCDS "only when it improves the net value of the projects they bid."[33] As discussed in Section II.B.1, developers today can offer a bid both with and without FCDS. The utility will then chose the project that is the best value for its bundled customers. The release of market sensitive information is not necessary to reduce costs to

---

[30] ORA, p. 3.
[31] IEP, pp. 5-6.
[32] D.06-06-066, p .4.
[33] CalWEA, p. 2.

customers. To the contrary, safeguarding market sensitive information protects the interests of bundled customers from those who would use this information to game their bids.

Calpine and GPI assert that greater transparency in the IOUs' capacity price projections would provide developers with better information about the value of capacity."[34] But, providing developers with better information about capacity prices will not protect bundled customers from developers making use of this information to the detriment of bundled customers. The Commission should protect bundled customers by allowing the IOUs to use their own utility-specific assumptions for evaluating RPS bids and by safeguarding that market sensitive information from public disclosure.

IV.

THE EXISTING LCBF METHODOLOGY IS APPROPRIATE AND SUFFICIENT

A. Contrary to GPI's Assertions, Structural Reform to LCBF is Not Needed

GPI states in their comments that "the GPI strongly recommends that structural reform of the underlying LCBF methodology itself be an essential component of the LCBF reform process, not just the various individual issues that have been identified for study."[35] This objective is contrary to the Commission's stated objectives for the LCBF reform process. The Commission has clearly stated its objectives in the staff paper, where the primary goals of LCBF reform are: 1) to ensure compliance, 2) improve market efficiency and 3) lay a foundation between RPS program and Integrated Resource Planning (IRP). The issues that the Commission included in the LCBF reform are based on statutory requirements, issues identified in RPS procurement plan process, and other emerging issues in resource planning, procurement, and grid integration. Given these already ambitious objectives, the Commission should not expand the scope of LCBF reform any further.

---

[34] *See* Calpine, p. 7; GPI, p. 5.
[35] GPI, p. 2.

SCE strongly supports the Commission's approach, which is, focused on addressing key areas related to LCBF methodology, i.e., Effective Load Carrying Capacity ("ELCC"), Capacity Price, TOD factors, valuation of deliverability status. Addressing these key areas will be a substantial undertaking. Since the Commission adopted D.03-06-071 in 2003, the LCBF methodology has gone through significant refinements as the RPS program and renewables market have matured. Several changes to the LCBF methodology in the past years[36] have continued to develop a robust foundation. The Commission can further strengthen the LCBF methodology through focus on the specific issues identified in the staff paper on LCBF reform.[37] Attempting a wholesale restructuring of the LCBF methodology will likely delay action on the targeted updates that can help to improve the existing methodology. Moreover, such a restructuring is not necessary because the existing methodology is generally working well. The latest RPS project status report from the Commission,[38] shows that the three IOUs have successfully selected and on boarded over 11,000 MW of RPS capacity since November 2007.

The Staff Paper offers a holistic approach that will increase the transparency and effectiveness of the LCBF process. A key area of focus in Track 1 of LCBF reform is a standardized methodology and inputs for the ELCC[39] and a standardized benchmark of capacity prices. A standardized methodology for ELCC and a benchmark of capacity prices has the potential to increase transparency of the LCBF process. Another key area of focus is the Renewable Integration Cost Adder ("RICA").[40] The revisions to the RICA calculation may have a major impact on LCBF and will play an important role in achieving the LCBF reform goals of

---

[36] LCBF has been revised several times based on the following decisions: D.04-07-029, D.05-12-042, D.09-06-018, D.12-11-016, D.13-11-024, D.14-11-042, and D.15-12-025.

[37] ALJ's Ruling, Attachment A, p. 6, Table 1.

[38] RPS Monthly Project Status Table, http://www.cpuc.ca.gov/RPS_Homepage.

[39] Administrative Law Judge's Ruling Accepting into the Record Revised Energy Division Staff Paper on the Use of Effective Load Carrying Capability for Renewables Portfolio Standard Procurement and Setting Schedule, p. 2 (filed March 9, 2016).

[40] On April 4, 2016 SCE filed its final RICA report in R.16-02-007 where a recommendation was made to conclude the RICA Study required by the March 27, 2015 ALJ's Ruling and initiate a new RICA study in R.16-02-007 (LTPP/IRP).

better transparency and alignment with the IRP. Similarly, evaluation of TOD factors and EO/FCDS project valuation methodology, along with track 2 and track 3 focus areas,[41] will help meet the objectives set for LCBF reform and further strengthen the existing LCBF methodology. Additional structural reform is unnecessary. Therefore, GPI's suggestion for further structural reforms to the LCBF process should be rejected.

B. Updates to RA Valuation Already Under Consideration Are Sufficient to Ensure EO and FCDS Projects on Are Accurately Valued

BAMx asserts that "[a]t present many generator developers are under the impression that they cannot successfully compete for a PPA without FCDS,"[42] and further that "LCBF methodologies do not necessarily accurately weigh the likely costs of FCDS resources placing them in an advantageous position relative to EO projects."[43] SCE disagrees with BAMx. The development of an ELCC methodology already underway at the Commission is sufficient to ensure that EO and FCDS projects are accurately valued.

As part of this proceeding, the Commission is already working with Investor-Owned electric Utilities ("IOUs") on the development and adoption of an ELCC methodology for use in RPS procurement.[44] On June 17, 2016, the IOUs submitted the Joint IOU Proposal[45] to the Commission on a standardized ELCC methodology and set of inputs and assumptions. The ELCC approach has the potential to be a more accurate measure for estimating the Net Qualifying Capacity of the intermittent resources than the traditional exceedance methodology.

---

[41] ALJ's Ruling, Attachment A, p. 6, Table 1.
[42] BAMx, p. 9.
[43] *Id.* At 12.
[44] Administrative Law Judge's Ruling Accepting into the Record Revised Energy Division Staff Paper on the Use of Effective Load Carrying Capability for Renewables Portfolio Standard Procurement and Setting Schedule, p. 2 (filed March 9, 2016).
[45] Joint Response of PG&E, SCE, and SDG&E to Administrative Law Judge's Ruling Accepting into the Record Revised Energy Division Staff Paper on the Use of Effective Load Carrying Capability for Renewables Portfolio Standard Procurement and Setting Schedule (filed June 17, 2016).

An ELCC methodology can consider the time specific needs of the system to more accurately assess the ability of a resource to meet reliability needs. The current exceedance methodology takes into account only the output capability of a resource during specific hours, currently set at the time of peak load need. As renewable penetration is increasing, the time horizon of net peak load, described as load minus solar and wind generation, is shifting away from the previously identified peak load hours. As a result, the current methodology might ascribe RA capacity value to the resource in the hours when system is not constrained. The ELCC methodology addresses this issue by modeling effective capacity value of a resource in meeting the overall electricity system reliability needs during both peak load and net load peak horizons. As the methodology is further developed and refined to more accurately measure the capacity contribution of intermittent resources, the current gap between EO and FCDS projects evaluation would potentially reduce.

C. Contrary to Arguments of BAMx, SCE's Congestion Adders Are Appropriate and Sufficient

BAMx claims that "the EO congestion cost adder attributed to the risk of congestion that utilities such as SCE impose on EO generation that is bid into its procurement process is arbitrary."[46] BAMx's comments show a lack of familiarity with the methodology used to calculate congestion adders for LCBF analysis. The current methodology that SCE uses to determine the EO congestion cost adder is a data-driven approach. SCE uses long-term California market-wide fundamental simulations with detailed California transmission system simulations to determine the congestion adder for the EO renewable projects. This methodology determines the EO congestion adder based on the congestion cost difference between the scenario case (including EO renewable projects) simulation and the base case (without EO

[46] BAMx, p. 8.

renewable projects) simulation for selected years. The final congestion cost adder is the average of congestion adder across these selected years.

V.

THE IRP PROCEEDING MORE APPROPRIATELY ADDRESSES CERTAIN ISSUES RAISED IN THE OPENING COMMENTS ON LCBF REFORM

A. It is Premature to Consider Consolidation of Procurement Frameworks

With respect to SDG&E's suggestion to move to a more holistic procurement process,[47] SCE agrees that the attributes of resources may span more than one of the current procurement processes (e.g., local capacity requirements ("LCR") and RPS, or storage and system flexibility) and that the interaction should be considered as possible. SCE believes it is premature to comment on a potential consolidation of procurement frameworks, however.

B. The Commission Should Ignore CEERT's Recommendation to Move Track 3 Issues to Track 1 as Many Track 3 Issues Are More Appropriately Scoped into R.16-02-007

CEERT argues that the Commission should move Track 3 issues, which relate to greenhouse gases ("GHG"), disadvantaged communities, integration adder, optimal portfolio, and resource diversity,[48] to Track 1.[49] SCE urges the Commission to ignore this recommendation as these Track 3 issues are in scope within R.16-02-007, related to SB 350's IRP process, and should be first addressed there. All of these issues, except the integration adder,[50] will be

---

[47] SDG&E, pp. 2-3.
[48] ALJ's Ruling, Attachment A, p. 6, Table 1.
[49] *See* CEERT, p. 5.
[50] The integration adder is scoped into R.16-02-007 as a carry-over from R.13-12-010. *See* R.16-02-007, "Joint Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge," pp. 10-11 (filed May 26, 2016).

addressed as part of the IRP framework and could require modeling work, among other things.[51] Addressing these Track 3 issues within this proceeding at this time risks adding inconsistency between the planning and procurement valuation processes counter to SB 350's intent to eliminate redundancy and increase efficiency.[52] As noted in SCE's opening comments, one possible outcome of the IRP process within R.16-02-007 could be a set of adders to inform the procurement valuation process, which consider GHG emissions reductions, among other resource characteristics.[53] To this end, the development of a RICA is scoped into R.16-02-007.[54]

C. **The LCBF Methodology Already Includes the Impact of Over-Generation on Market Prices; System-Wide Curtailment Issues Should Be Addressed in R.16-02-007**

SCE disagrees with CalWEA's, CBEA's, Ormat's, and Calpine's recommendation to address energy curtailments, and specifically the cost of mitigating curtailments at the system-wide level, through TOD factors in the LCBF methodology.[55] TOD factors are not the appropriate mechanism to deal with these issues. The LCBF methodology already appropriately differentiates the direct cost of project-specific curtailment in two ways: (1) through bid-in energy prices;[56] and (2) through both the quantitative and qualitative factors in the LCBF methodology.[57]

---

51 *See* PUB. UTIL. CODE §§ 454.51(a), 454.52(a)(1)(A), (F), (H).

52 *See Id.* §§ 454.52(d).

53 Opening Comments of SCE on Least Cost, Best Fit Reform, pp. 3 (filed July 22, 2016).

54 R.16-02-007, "Joint Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge," pp. 10-11 (filed May 26, 2016).

55 *See* CalWEA, pp. 4, 6.; CBEA, pp. 3-4; Ormat, p. 4; and Calpine, pp. 1-2. GPI also generally recommends that this proceeding should address curtailment, GPI, p. 4.

56 *See* SCE's Final 2015 RPS Procurement Plan, Volume 1, p. 25 "This is compounded by the likelihood that rational sellers have 'priced in' the cost of these curtailments."

57 *See Id.,* Volume 2, Public Appendix I.1, p. 9. "These additional [qualitative] characteristics may include: Congestion, negative price, and curtailment considerations not captured in the quantitative valuation."

This proceeding is also not the appropriate venue to discuss the cost of mitigating the indirect costs of curtailment at the system-wide level. Rather, system-wide issues should be addressed in R.16-02-007, which is intended to develop an IRP framework in accordance with SB 350's directive to optimize resource planning to achieve GHG emissions reductions and other state goals at the least cost. Development of a "renewables integration cost adder or alternative approach to valuing integration costs and benefits in the portfolio"[58] is already scoped into R.16-02-007 and is designed to quantify the incremental cost of additional renewable resources on the system, including potential curtailment costs impacts and flexible capacity needs to mitigate curtailment.

VI.

UTILITIES DO NOT HAVE INCENTIVES TO ENCOURAGE FCDS PROJECTS

In its opening comments, BAMx asserts that utilities have "perverse incentive[s]… . . . to prefer FCDS over EO projects" because utilities can "obtain enhanced rate of return and protection from any risk on investments in transmission to facilitate FCDS resources."[59] BAMx is wrong that utilities have perverse incentives. First, from a procurement perspective, SCE selects resources that offer the least cost, best fit for SCE customers, independent of what entity, if any, is earning a rate of return on the transmission upgrades. That selection includes consideration of any transmission network upgrade costs that would be paid for by SCE customers which are added to the bid of the resource, as applicable. Second, from a transmission perspective, transmission network upgrades are reviewed and approved through the CAISO's GIDAP process consistent with the CAISO tariff that was accepted by FERC. Thus SCE – or any other transmission owner for that matter – cannot independently approve transmission

58 R.16-02-007, "Joint Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge," pp. 10-11 (filed May 26, 2016).

59 BAMx, p. 12.

upgrades whose costs are recovered from customers as part of the Transmission Revenue Requirement.

VII.

ALL CUSTOMERS SHOULD PAY FOR PROCUREMENT FOR SOCIAL BENEFITS

In its opening comments, GPI asserts that "economic-development benefits should be considered as a component of the LCBF."[60] First, special consideration for specific development areas is already addressed in RPS Calculator through policy driven lines, and therefore no additional consideration needs to be taken as a separate component of the LCBF. Second, to the extent that IOUs are directed to procure resources to support social benefit causes, such as economic development, in a way that increases costs for customers, all electric customers should pay to support these efforts. The CPUC should not solely direct IOU bundled customers to pay for contracts that incur additional costs as it is anti-competitive and unfair to bundled customers.

---

[60] GPI, p. 4.

Respectfully submitted,

JANET S. COMBS
CAROL SCHMID-FRAZEE

/s/ Carol Schmid-Frazee
By: Carol Schmid-Frazee

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1337
Facsimile: (626) 302-1935
E-mail: Carol.SchmidFrazee@sce.com

August 9, 2016

<u>**VERIFICATION**</u>

I am a Manager in the Regulatory Affairs Organization of Southern California Edison Company and am authorized to make this verification on its behalf. I have read the foregoing **REPLY COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON LEAST COST, BEST FIT REFORM**. I am informed and believe that the matters stated in the foregoing pleading are true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this **9th day of August, 2016**, at Rosemead, California.

/s/ Janos Kakuk
By: Janos Kakuk

SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770